Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 – 28 November 2015

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 22 to 28 November 2015. There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $47/MWh and above $250/MWh. There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $52/MWh and above $250/MWh. There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $92/MWh and above $250/MWh.

Figure 1: Spot price by region ($/MWh)

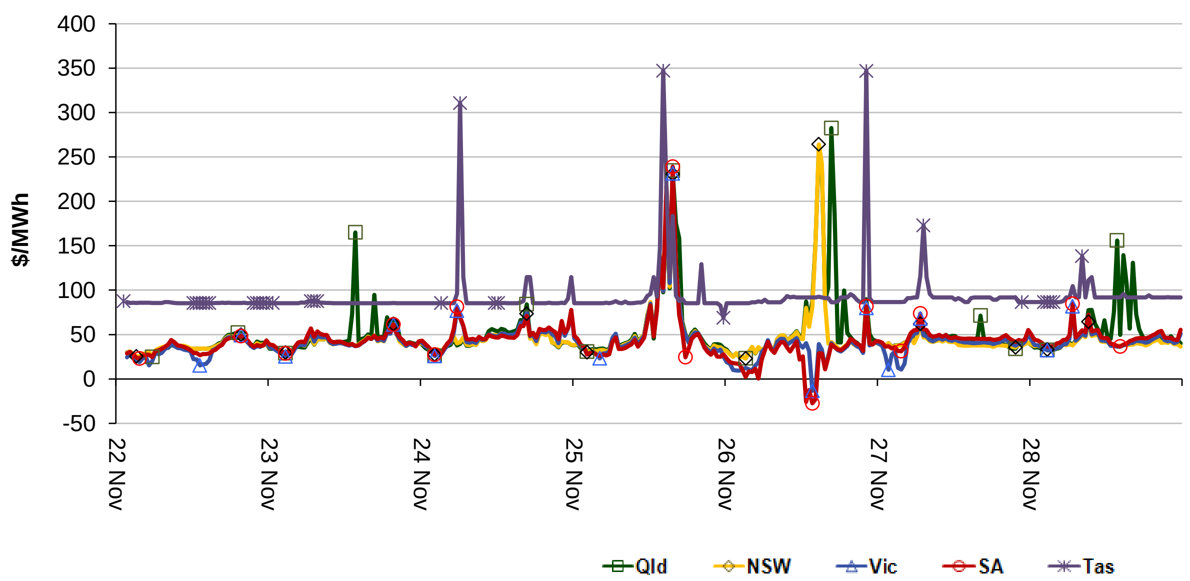


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

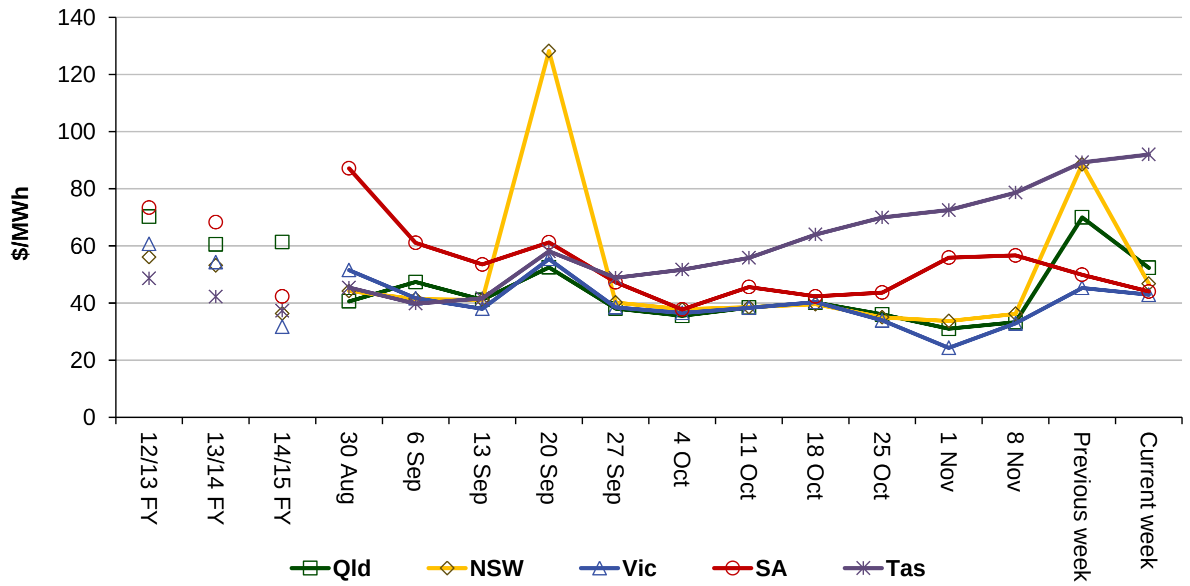


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	52	47	43	44	92
14-15 financial YTD	33	38	34	42	37
15-16 financial YTD	44	46	38	61	50

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 113 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

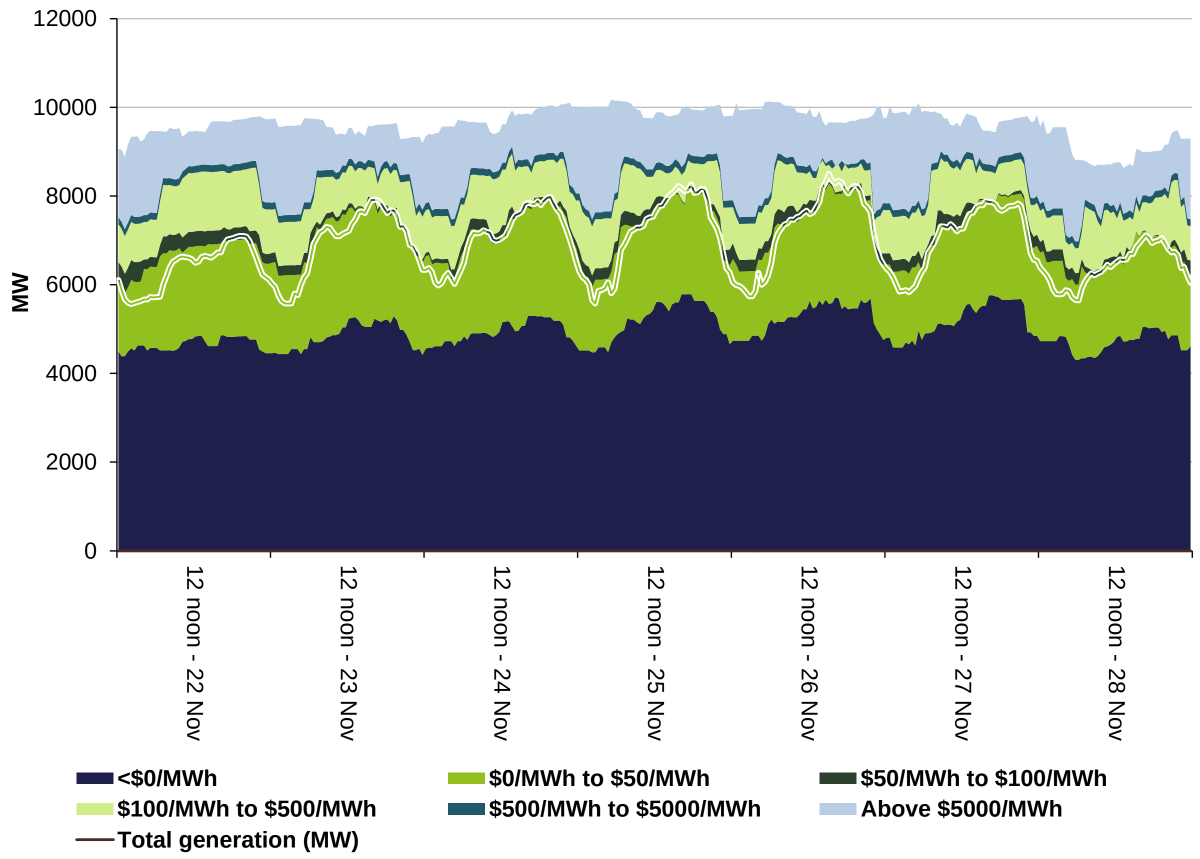
	Availability	Demand	Network	Combination
% of total above forecast	8	63	0	0
% of total below forecast	27	2	0	0

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

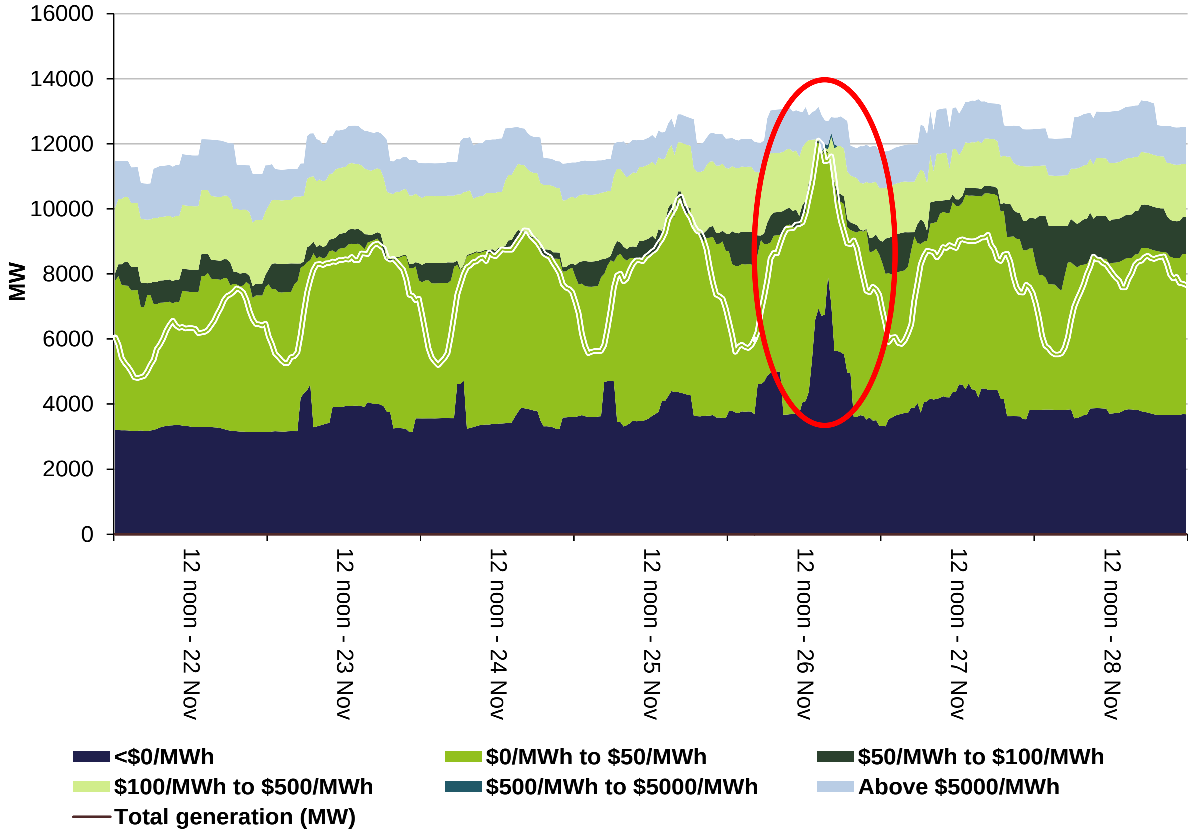
The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns



The red ellipse on Figure 4, following, highlights periods where high prices occurred in New South Wales. Demand on these days was high and, as can be seen from the figure, there was limited capacity available between low prices and prices greater than $5000/MWh.

Figure 4: New South Wales generation and bidding patterns



The red ellipse on Figure 5, following, corresponds to the periods where high prices occurred in New South Wales but where the Victorian generators shifted capacity into prices between $100/MWh and $500/MWh.

Figure 5: Victoria generation and bidding patterns

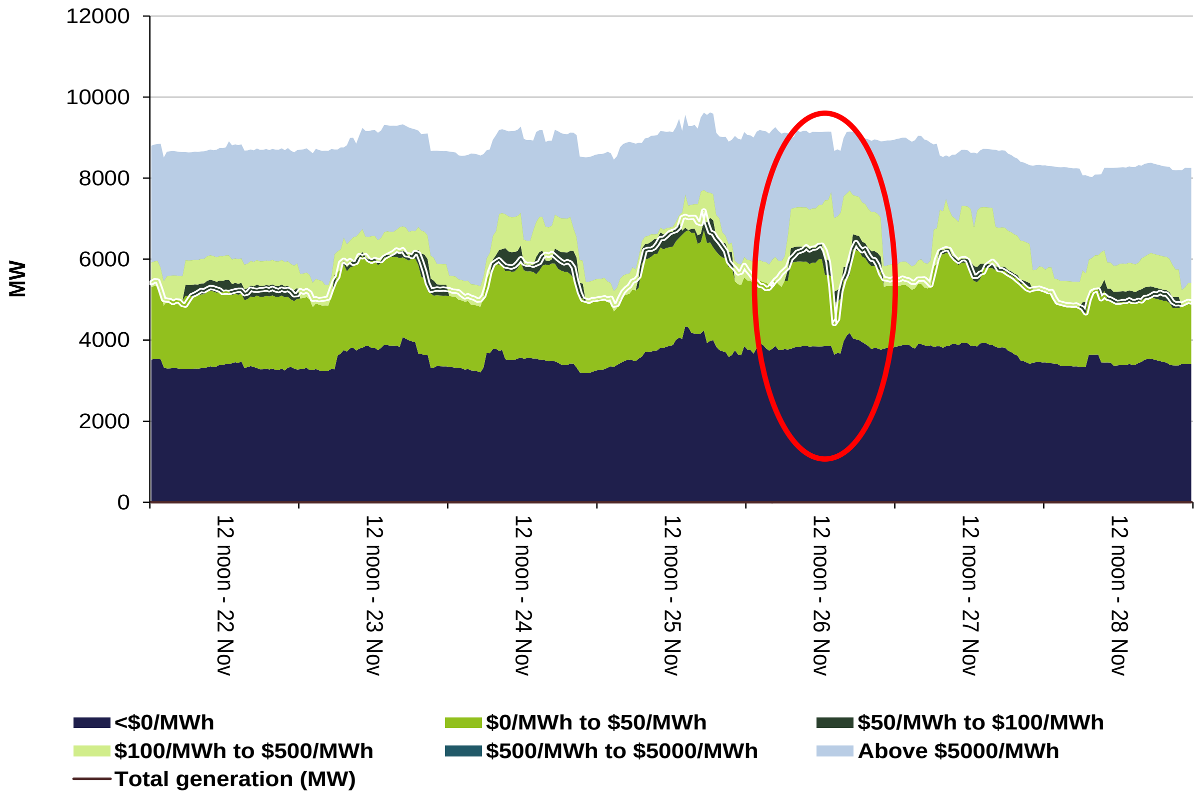


Figure 6: South Australia generation and bidding patterns

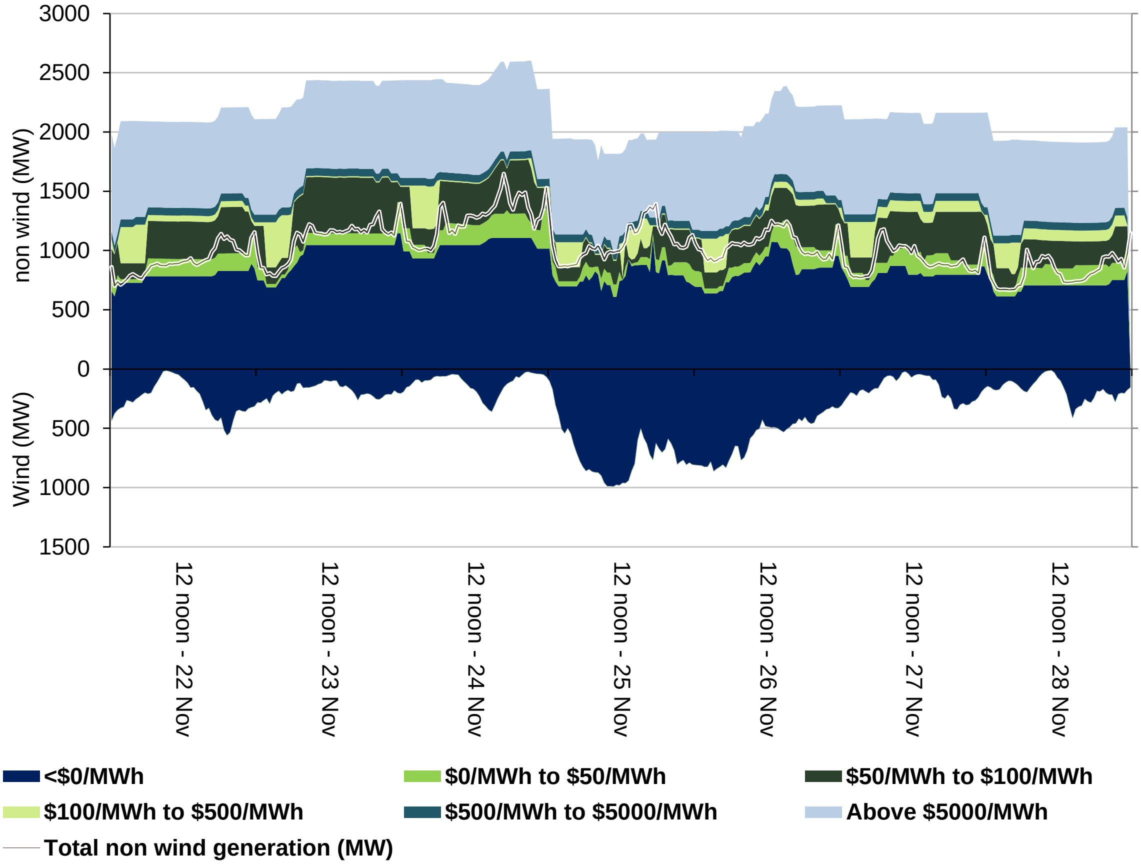
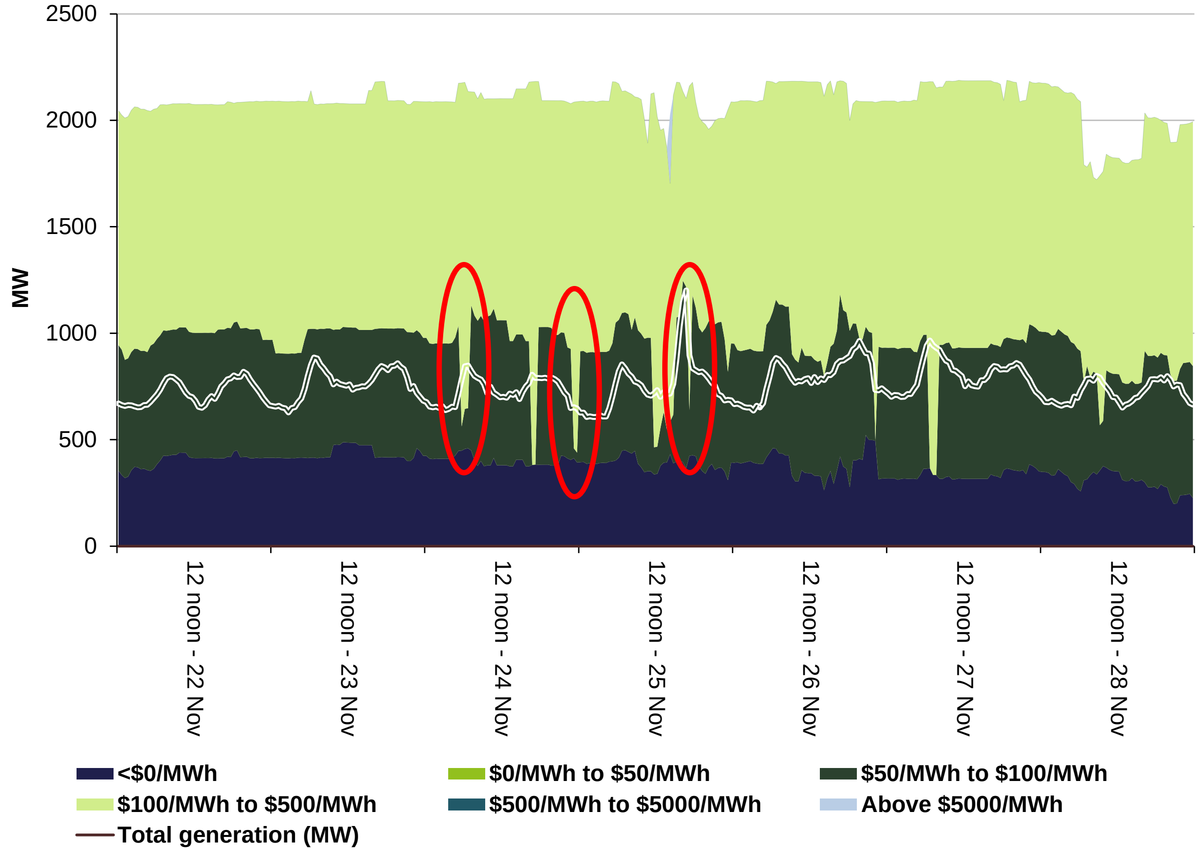


Figure 7: Tasmania generation and bidding patterns



The red ellipses on Figure 7 show where Hydro Tasmania rebid resulting in the prices detailed in the "Detailed market analysis of significant price events" section.

Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

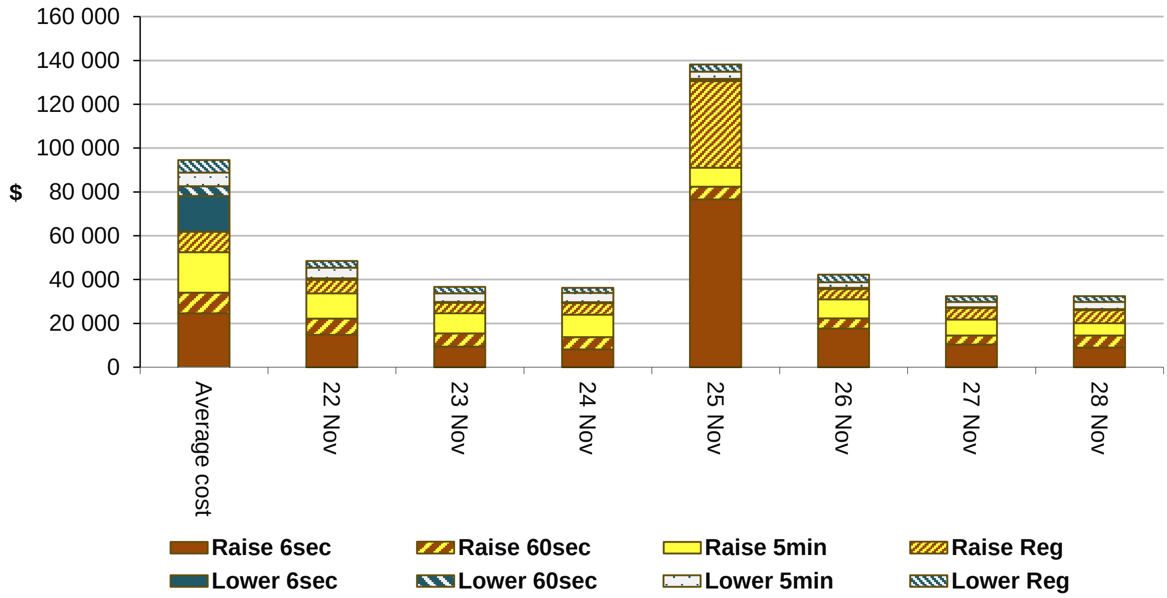
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $196 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $170 500 or 1 per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $47/MWh and above $250/MWh.

Thursday, 26 November

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	264.15	42.95	47.14	11 492	11 031	10 126	13 087	13 560	13 524

Conditions at the time saw demand 361 MW above forecast four hours ahead and 1366 MW above that forecast 12 hours ahead. Available capacity 463 MW below forecast four hours ahead. Prices were aligned with those in Queensland.

For the duration of the 3 pm trading interval a constraint managing the outage of the Dapto to Kangaroo Valley line saw a flow forced from New South Wales into Victoria across the Vic-NSW interconnector from between 200 MW and 850 MW. This constraint also constrained down low-priced generation in Southern New South Wales.

Table 4: Rebids for the 3 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.59 pm		Delta Electricity	Vales Point	90	<50	>290	1357A 5MIN PD DEMAND IS 200MW HIGHER THAN HH PD DEMAND AT 1500- SL
2.04 pm		EnergyAustralia	Tallawarra	100	30	13 111	14:02 A ADJ BANDS CHG V-NSW IC FLOW/ CON MAN N>>N-DTKV_E
2.26 pm	2.35 pm	EnergyAustralia	Tallawarra	100	30	13 111	14:25 A ADJ BANDS NSW $/DEM > 30MPD FCST 11316/11223 81.09/49.95
2.34 pm	2.45 pm	AGL Energy	Liddell	-70	<50	N/A	1430~P~010 UNEXPECTED/PLANT LIMITS~PLANT ISSUES 380MW REQUIRED
2.46 pm	2.55 pm	EnergyAustralia	Mt Piper	140	35	13 405	14:43 A ADJ BANDS MAT CHG $NSW PD5 FCST FR 1500: 1445.21 @1540
2.53 pm	3 pm	Snowy Hydro	Tumut	-240	-1000	N/A	14:53:P PLANT OUTAGE: T3 U5

As a result of the above rebidding and higher than forecast demand all but the 2.40 pm dispatch interval price was around $300/MWh.

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $52/MWh and above $250/MWh.

Thursday, 26 November

Table 5: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	259.82	43.82	49.51	7889	7870	8009	9634	10 045	10 063

Conditions at the time saw demand close to forecast but available capacity was 411 MW below forecast four hours ahead. The price was aligned with that in New South Wales.

Table 6: Rebids for the 3 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.03 pm		CS Energy	Gladstone	-170	<34	N/A	1402P OIL LINE LEAK UNIT RAMPING OFF LINE-SL
2.17 pm		ERM Power	Oakey	55	0	>295	1407F CHANGE IN CONTRACT POSITION-

The above rebids as well as the rebidding in New South Wales saw all but the 2.40 pm dispatch price at around $300/MWh.

Table 7: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5 pm	282.49	44.18	49.51	8372	8235	8349	9658	9975	10 060

Conditions at the time saw demand close to forecast but available capacity around 300 MW lower than forecast. A dynamic constraint avoiding the overload of the Liddell to Muswellbrook line was limiting imports into Queensland to around 100 MW.

Table 8: Rebids for the 5 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.53 pm		CS Energy	Gladstone	-250	<75	N/A	1352P OIL LINE LEAK UNIT RAMPING OFF LINE-SL

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.17 pm		ERM Power	Oakey	60	0	12 899	1407F CHANGE IN CONTRACT POSITION-
4.03 pm		ERM Power	Oakey	100	<0	350	1602A CHANGE IN NSW DEMAND 5M DISPATCH 11351MW VS 30M PD 11618MW
4.48 pm	4.55 pm	Callide	Callide C	80	17	13 800	1647A CHANGE IN 5MIN PD DEMAND - SL
4.51 pm	5 pm	Millmerran	Millmerran	105	7	13 800	16:49A 87 MW CHANGE IN 5MIN PD DEMAND FOR DI 17:00 RUNS 1645/50

The above rebidding and limited imports into Queensland resulted in the dispatch prices between $200/MWh and $300/MWh for the entire trading interval.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $92/MWh and above $250/MWh.

Tuesday, 24 November

Table 9: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 am	310.58	87.42	88.30	1150	1172	1164	2179	2181	2182

Conditions at the time saw demand and available capacity close to forecast.

At 5.49 pm, Hydro Tasmania rebid 481 MW of capacity across their portfolio from less than $96/MWh to $347/MWh. The reason given was “0550A Basslink flow different from forecast”.

At 5.58 pm, effective from 6.10 pm, Hydro Tasmania rebid 150 MW of capacity at Poatina from $115/MWh to prices greater than $347/MWh. The reason given was “0600A act. Vic price higher than forecast.”

The above rebidding coupled with demand increasing towards the morning peak saw the 6.10 pm dispatch price rise to $347/MWh and remain there for the rest of the trading interval, resulting in a $311/MWh spot price.

Wednesday, 25 November

Table 10: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
2.30 pm	347.01	85.33	85.33	1100	1064	1041	2027	2145	2160

Conditions at the time saw demand close to forecast, and available capacity slightly below forecast.

Table 11: Rebids for the 2.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.14 pm		Hydro Tas	Portfolio	239	<115	347	1315A PRICE > FORECAST: VIC
1.41 pm		Hydro Tas	Cethana	-93	<347	N/A	1340P PLANT FAILURE
1.55 pm	2.05 pm	Hydro Tas	Portfolio	402	115	>347	1355A PRICE > FORECAST: VIC

From 2.05 pm the dispatch price increase to $347/MWh and stayed there for the entire trading interval.

Thursday, 26 November

Table 12: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
10.30 pm	346.71	114.44	101.40	984	1070	1076	2084	2096	2095

Conditions at the time saw demand and available capacity slightly lower than forecast.

Table 13: Rebids for the 2.30 pm trading interval

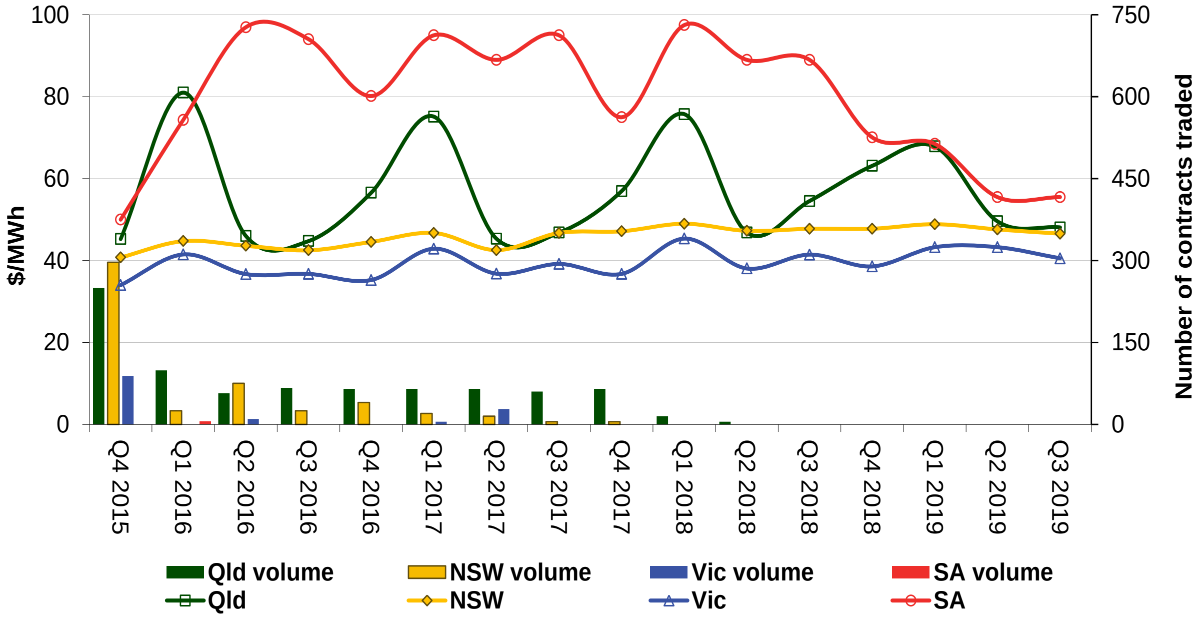
Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.43 pm		Hydro Tas	Gordon	114	92	347	2045E CORRECTING ERROR IN PREVIOUS BID
9.17 pm		Hydro Tas	Portfolio	759	115	469	2120E CORRECTING ERROR IN PREVIOUS BID

The above rebidding saw the dispatch price rise to $347/MWh and remain there for the duration of the trading interval.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

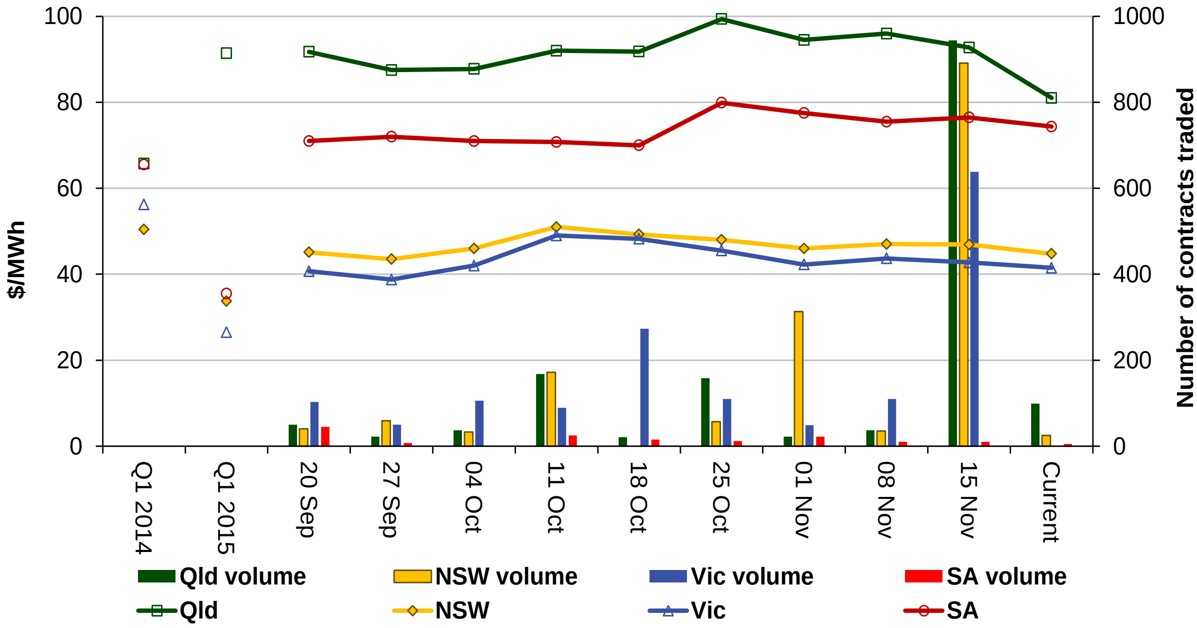
Figure 9: Quarterly base future prices Q4 2015 – Q3 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



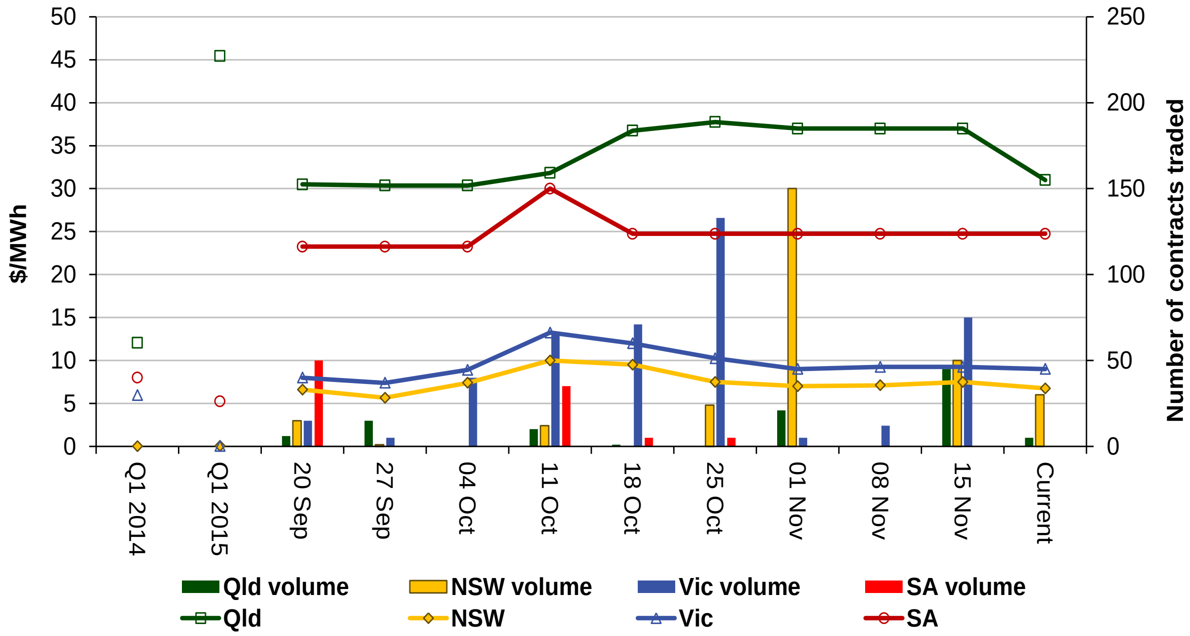
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional Quarter 1 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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